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Reliability Assesment of Debremarkos Distribution System Found In Ethiopia

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Abstract- This research presents a method for reliability assessment considering the 23MVA, 230/15 kV transformer through two 15 kV outgoing transmission lines at Debre Markos substation. It also goes further to include 139 low voltage 15/0.4 kV distribution transformers. The total load connected to the 15 kV feeders are varies between 0.33255 and 6.3185 MW. A composite system adequacy and security assessment is done using Monte Carlo simulation. The basic data and the topology used in the analysis are based on the Institution of Electrical and Electronics Engineers **-** Reliability Test System and distribution system for bus two of the IEEE-Reliability Bus bar Test System. The reliability indices SAIDI, SAIFI, CAIDI, EENS, AENS, ASAI, ASUI, and expected interruption costs are being assessed and considered. Distribution system reliability information was obtained from actual data for systems operating in Ethiopia Electric Utility office and Debre Markos substation recorded data and online SCADA system.

Keywords: Adequacy, DigSILent, Expected Interruption cost, Failure rate, Forced outage, Indices, Interruptions, Reliability, Repair time, Security.

I. INTRODUCTION

The electric power systems can be divided into generation plant, generation sub-station, transmission system, sub-transmission and distribution sub-stations. Traditionally, generation is to supply the power to the transmission system which can be defined as the carrier of power from the generating stations to the sub-transmission system, at voltage levels of 230 kV or higher. The sub-transmission system then transfers the power at voltage levels between 66 kV to 132 kV to the distribution substation systems. Finally, the distribution substation system, at voltages under 33 kV, delivers electricity to the consumer [1].

The case study of radial distribution system reliability assessment is carried out on Debre Markos Substation system which consists of 66kV, 33kV and 15kV outgoing feeder network in Debre Markos. The reliability assessment analysis through 230/15KV, 23MVA transformer is done on two 15kV feeders (feeder-3 and feeder-4) system to assess the performance of existing system to reliability indices analysis considering customer and system configurations. The alternative technique which shows reliability indices such as SAIDI, SAIFI, CAIDI, EENS, and EIC are being assessed and considered. Recent and unpublished important information and data have been collected from Debre Markos Substation. Interviews with respective professionals at substations and Electric utility office have been considered. The collected data are; fault statics, outage consequences, the number of interruption, interruption duration, the existing distribution network capacity, the capacity of power supplied to the network, the number of connected feeders, the minimum, mid-range, maximum demands per day/month/year, the distance from the transmission line to the distribution, and from distribution to main feeders of the study area have been collected from Ethiopia electric power and Ethiopia electric utility offices. The distribution system model for reliability analysis using DIgSILent software tool was developed.

This study considered the two 15kV outgoing feeders (Debre Markos line 3 and line 4) in the town. This is because the distribution system is the major contributor of the reliability problems in the power system more than 80% [2].

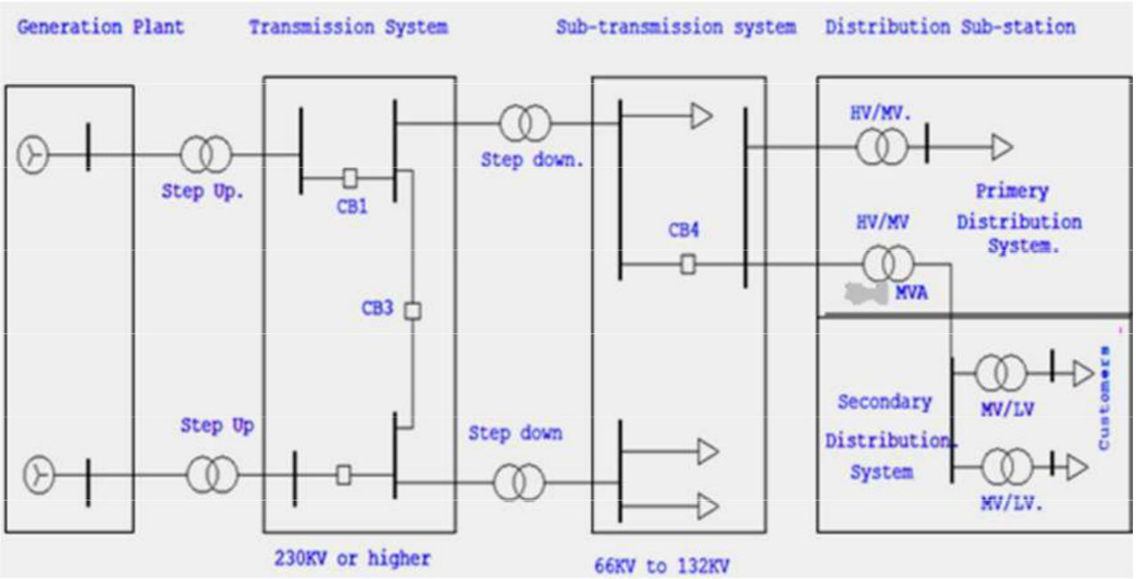


Figure 1.1: **Basic power system structure.**

2. SYSTEM MODEL

2.1. Distribution system Reliability Indices

The most commonly used reliability indices of distribution systems are statistical aggregations of reliability data for defined loads, components or customers. They are mostly average values of a particular reliability characteristic for an entire system, operating region, distribution service area or other portion of the system. The indices can be categorized as customer based and load based indices [3-6].

2.1.1. Customer Based Indices

System Average Interruption Frequency Index: (SAIFI) is measure of how many sustained interruptions on average customer will experience over the course of a year. For a fixed number of customers, the only way to improve SAIFI is reduce the number of sustained interruption experienced by customers [3-6].

$$SAIFI = \frac{\text{Total number of customer interruptions}}{\text{Total number of cutemer served}} = \frac{\sum \lambda i\ Ni}{\sum Ni} \qquad (1)$$

System average interruption duration index: (SAIDI) is a measure of how many interruption hours on average customer will experience over the course of a year. For a fixed number of customers, SAIDI can be improved by decreasing the number of interruptions or by decreasing the duration of these interruptions. Since both of these reflect reliability improvements, a reduction in SAIDI means an improvement in reliability [3-6].

$$SAIDI = \frac{\text{Sum of customer interruptions durations}}{\text{Total number of customer}} = \frac{\sum Ui\ Ni}{\sum Ni} \qquad (2)$$

Customer average interruption duration index: (CAIDI) is a measure of how long an average interruption lasts, and is used as a measure of utility response time to system incidents. CAIDI can be improved by decreasing the length of interruptions, but can also be decreased by increasing the number of short interruptions. As a result, a decrease in CAIDI does not necessarily mean an improvement in reliability [3-6].

$$CAIDI = \frac{\text{Sum of customer interruptions durations}}{\text{Total number of customer interruptions}} = \frac{\sum Ui\ Ni}{\sum \lambda i\ Ni} \qquad (3)$$

Average service availability index: (ASAI) is the customer-weighted availability of the system and provides the same information as SAIDI. Higher ASAI values means higher level of system reliability [3-6].

$$ASAI = \frac{\text{Customer hours of available service}}{\text{Customer hours demand}} = \frac{8760 \times \sum N_i - \sum U_i N_i}{8760 \times \sum N_i} \quad (4)$$

Average service unavailability index:

$$ASUI = \frac{\text{Customer hours of unavailable service}}{\text{Customer hours demand}} = \frac{\sum U_i N_i}{8760 \times \sum N_i} \quad (5)$$

Where N_i is the number of customers for load point i, U_i is the annual outage duration for load point , λ_i is the number of occurrence of sustained interruption at load point i and 8760 is the number of hours in a calendar year [3-6].

2.1.2. Load and Energy Based Indices

One of the important parameters required in the evaluation of load and energy based indices is the average load (L_a) at each load point bus bars, which is given by: [3-6]

$$L_a = L_{peak}\, f$$

Where;
L_{peak} is the peak load demand
f is the corresponding load factor

Expected Energy Not Supplied Index at Load Point:
EENS = Expected total energy not supplied by the system = $\sum U_i L_{a(i)}$

Average Energy Not Supplied:

$$AENS = \frac{\text{Total energy not supplied}}{\text{Total number of customers served}} = \frac{\sum_i U\, L_{a(i)}}{\sum_i N}$$

2.2. Software Implementation Procedure for Reliability Evaluation

DIgSILent is a computer aided engineering tool for the analysis of industrial, utility, commercial, and residential electrical power systems. It has been designed as an advanced integrated and interactive software package dedicated to electrical power system and control analysis in order to achieve the main objectives of planning and operation optimization.

DIgSILent reliability evaluation software can be used to provide not only the reliability indices for both the individual load points and the overall power system, but also it can be used to provide the cost of interruptions. DIgSILent is based on Monte Carlo simulation and enumeration techniques. **Figure 2.1** shows the reliability evaluation procedure taken in DIgSILent to achieve the reliability indices for both load point and the overall system.

The first step is to analyze all the input data required for power flow analysis and data required for reliability evaluation. After processing the data and solving the power flow program for the system in order to obtain the system characteristics in normal condition, the system will be modeled by applying the MCS. The achieved model will be reduced to the reasonably small model by applying the contingency and ranking or the truncation of states techniques. But applying such techniques require a deep understanding over practical systems i.e. it is necessary to know what kind of outages may occur in practical system. In DIgSILent

the predefined outages events are categorized in two groups' i.e. first order and second order contingencies.

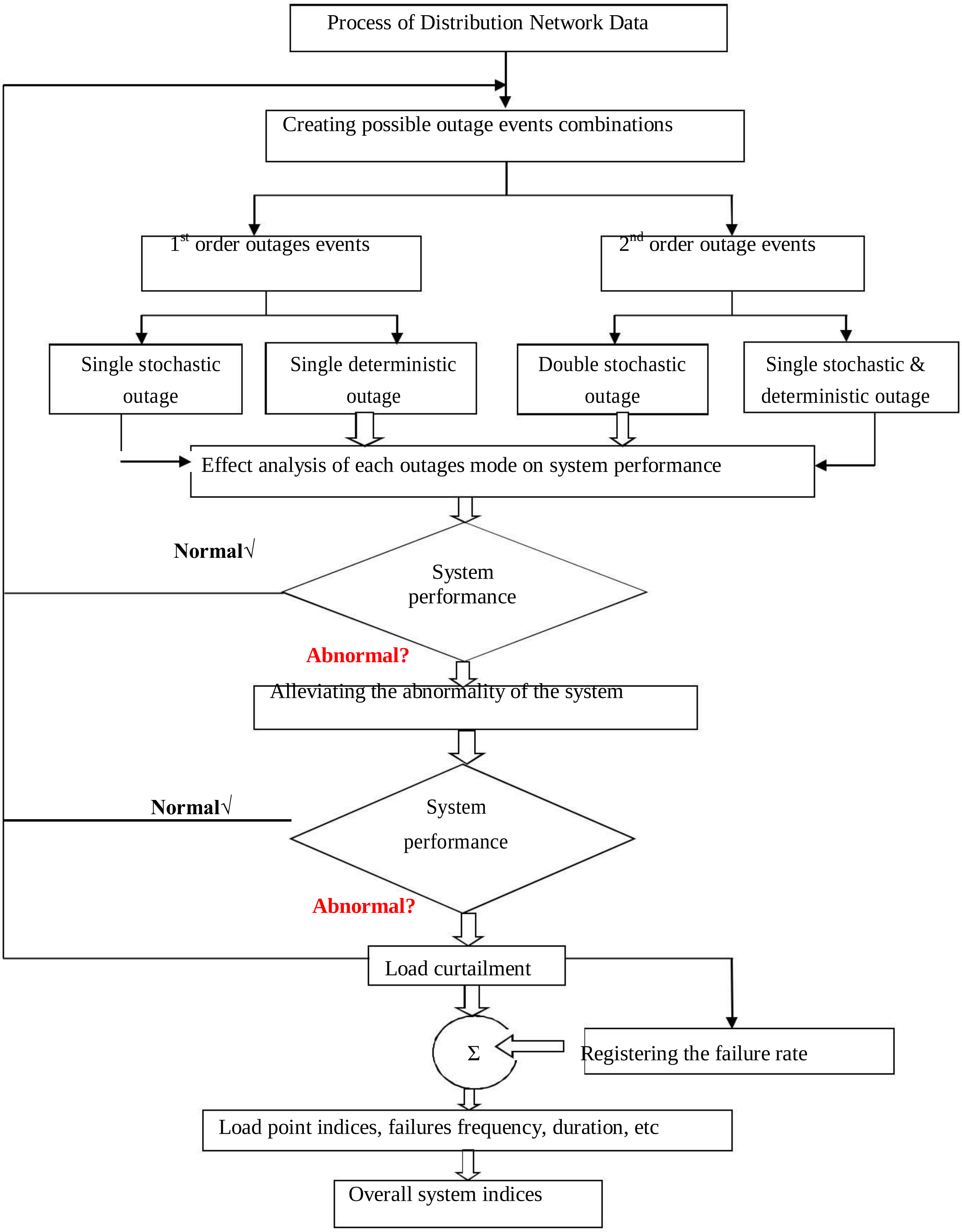


Figure 2.1: Flow chart for reliability evaluation of the distribution system

The second step is to create a first order and second order outage combinations. First order contingencies deal with single stochastic outages and single deterministic outages. Generally the single deterministic group does not contribute in interruption frequency while it causes no supply interruption to the loads of the system. Single stochastic outages group includes several modes such as independent single outage, common mode outage, ground fault and unintended switch opening. The reliability input data for these categories are failure rate and repair time and the output data are failure frequency and its relevant duration.

2.3. Case Study Reliability Assessment

To get some insight in the problems related to operation of a real distribution network, a case study based on the distribution system around Debre Markos and 15km South from Debre Markos town has been performed. The basis for the study is firstly a steady state load flow model of the 15 and 0.4 kV network which has been created and is maintained by the distribution network operator, and secondly measurements from the supervisory control and data acquisition system (SCADA) of the distribution system.

The substation supplies 10670 customers. The utility owns the distribution lines at 66, 33, 15 and 0.4 kV levels. The grid is only connected to the transmission system through the 230/66 kV, 230/33 kV and 230/15 kV substation. There are two parallel connected 400/230 kV, another 230/33kV and a third three winding 230/66/15kV transformer stations. This research considers only the 230/15 kV transformer through two 15 kV outgoing feeders and it also 139 total low voltage distribution transformers.

The 66, 33 and 15 kV system consists of overhead transmission lines, but 0.4 kV systems are considered a part of the loads. A general one line diagram of the 66, 33 and 15 kV grid including the neighboring 230 kV lines and the 400 kV in feed is shown in **Figure 2.3**. The 15 kV network is operated as radials and the total capacity of 230/66/15 kV transformer is 63MVA supply to two 66 kV (FINOTE SELAM and BICHENA) and supply to four 15kV (AMANUAL line 1, LUMAME line 2, Debre Markos Line 3 and Debre Markos Line 4) outgoing feeders. The total load connected to the two 15 kV feeders (Debre Markos Line 3 and Debre Markos Line 4) are varies between 0.33255 and 6.3185222 MW.

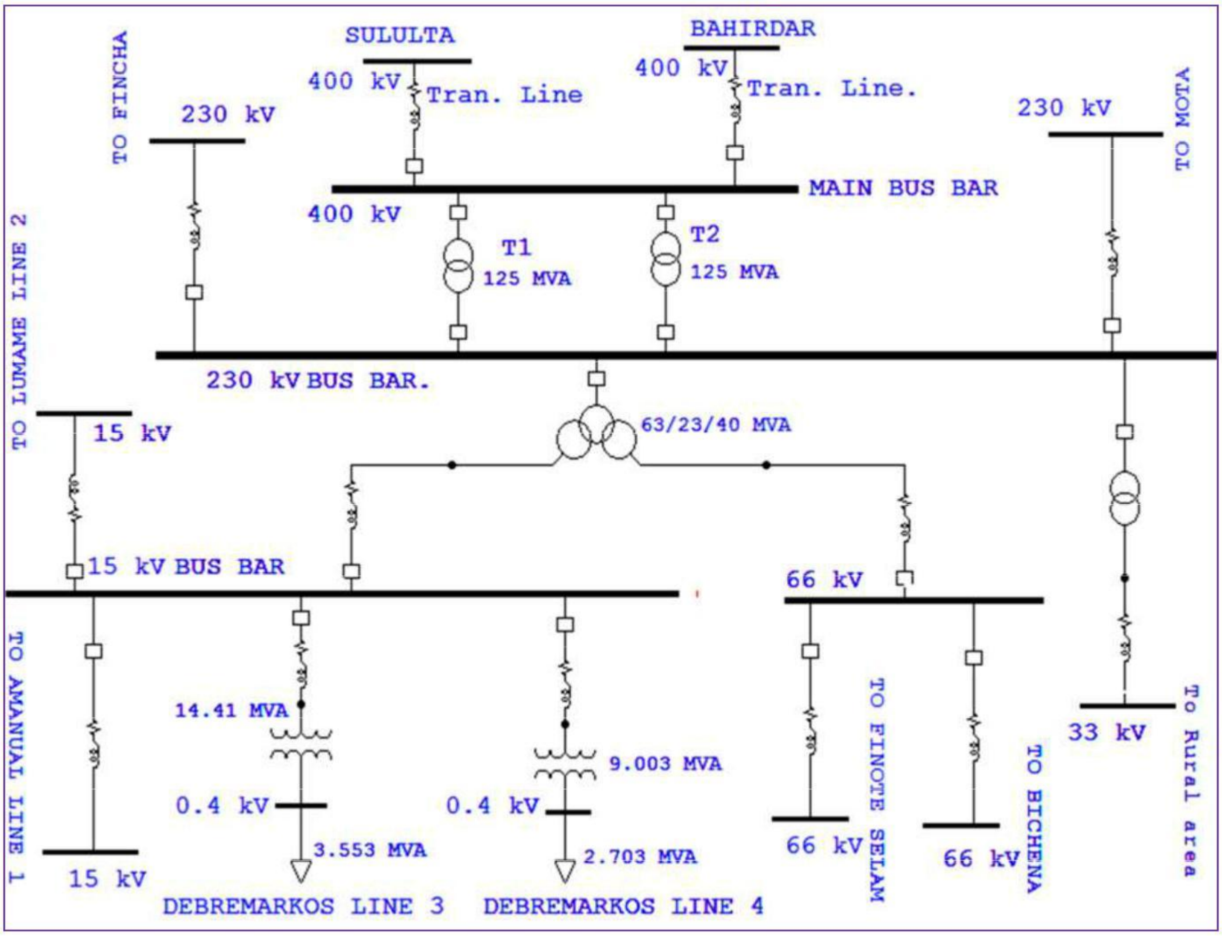


Figure 2.2: ETAP-Model Single line diagram of Debre Markos Substation

2.4. Distribution Substation test system

The base case distribution system modeled with ETAP software is shown in Figure 2.2. The peak loading levels of the two feeders (feeder-3 and feeder-4) is **6.31852MW** and the average load is **2.972MW**. It is assume a 100% of reliability performance from generation and transmission of the RBTS. There is one 230KV main bus that corresponds to bus 2 from Figure 2.3: which is connected to the 15KV supply point through substation transformer. Though the 15KV feeder the power supply is limited by having only one 23MVA, 230/15KV transformer capacity, there are four main feeders, Amanuel line 1, Lumame line 2, Debre Markos line 3, and Debre Markos line 4 at 15 KV, the feeders operate as radial system.

The main feeder names, detail transformers numbers, ratings, connected numbers of customers and remarks of low voltage outgoing feeders are shown in Table 2.1. The distribution system has 12 load points that supplies power to different types of costumer's loads, such as residential, commercial and industrial, the customers, minimum load, peak load and average load data at each feeder is shown in Table 2.2.

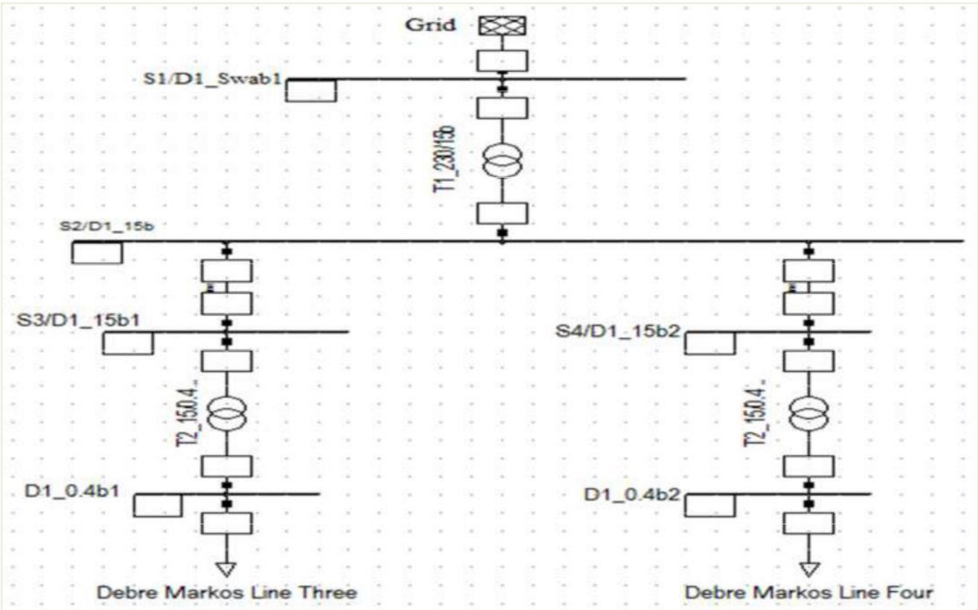
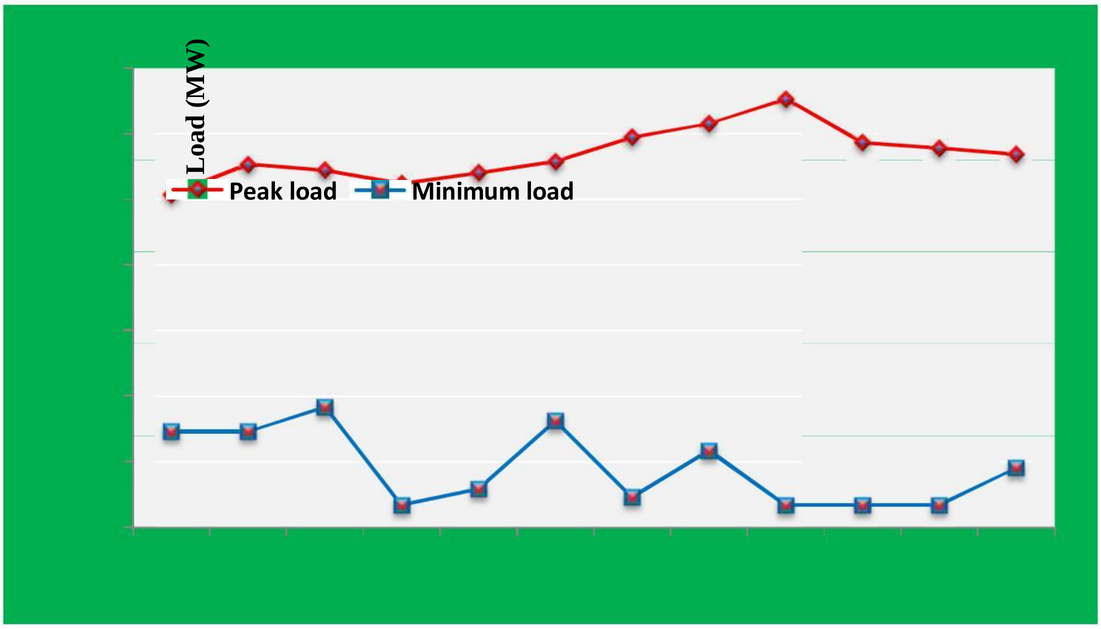


Figure 2.3: The Base Case Distribution Substation Model Using DIgSILent.

The minimum and maximum recorded load profile of feeder-3 and feeder-4 is presented in Figure 2.3 and Figure 2.4 in the year 2015.



Sept. Oct. Nov. Dec. Jan. Feb. March April May June July Aug.

Months

Figure 2.3: Peak and Minimum Load Profile of Feeder Three (Debre Markos Line-3)

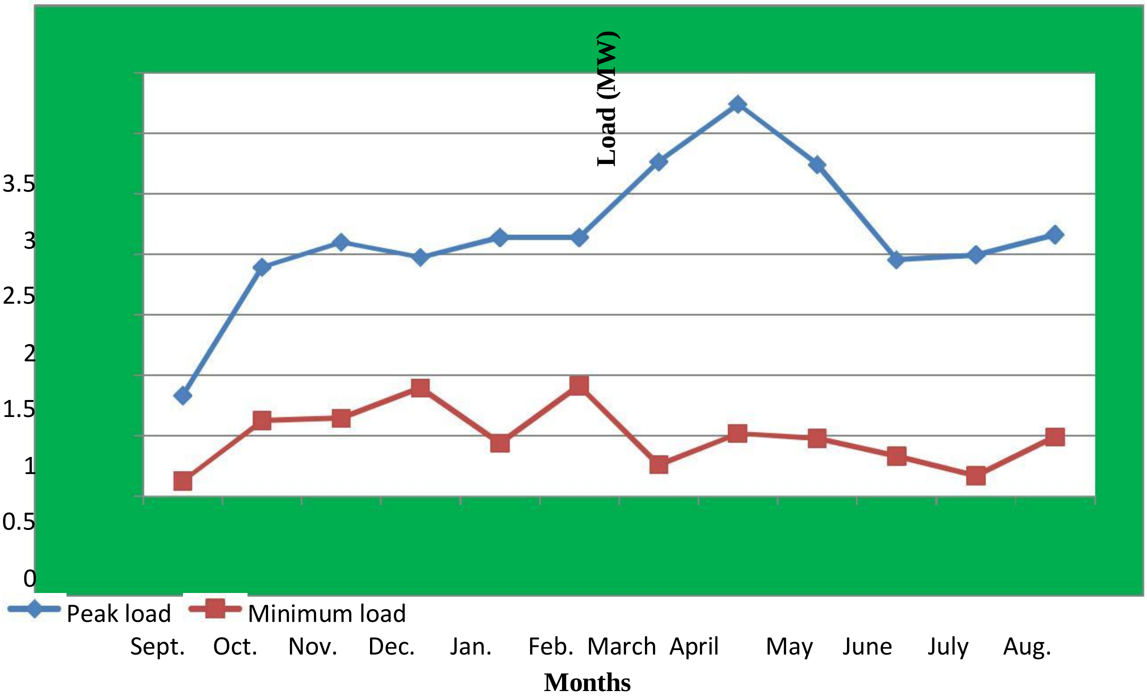


Figure 2.4: Peak and Minimum Load Profile of Feeder Four (Debre Markos line 4)

2.5. Case Study Area Major Source of Power Interruption

From historical data of the past years, major cause of outages, occurrences, and durations in the system is being evaluated and presented in Table 2.2 and Table 2.3.

Table 2.2: Causes of outage and number of occurrences in Debre Markos line-3 and -4

Feeder 3	Causes	DPEF	DPSC	DTEF	DTSC	OP	Sum
	No. of occurrences	116	74	116	64	320	690
Feeder 4	No. of occurrences	57	45	53	49	242	446
Total number of occurrences		173	119	169	113	562	1136

Table 2.3: Causes of outage and interruption duration in Debre Markos line-3 and -4

Feeder 3	Causes	DPEF	DPSC	DTEF	DTSC	OP	Sum
	Interrupted hours	134.9167	178.45	4.467	3.167	298	619.001
Feeder 4	Interrupted hours	142.433	118.1	2.7167	2.033	260.0833	525.366
Total	interrupted hours	277.3497	296.55	7.1837	5.2	558.0833	1144.367

3. SIMULATION RESULT AND DISCUSSION

The DIgSILent software simulation result of reliability indices of Debre Markos substation for each feeders are shown in Table 3.1, as a radial system with no meshed connections the failure rate (λ/yr), the outage durations (hr) and annual outage durations (hr/yr) and also Figure 3.1 shows outage duration and failure occurrence of each feeder.

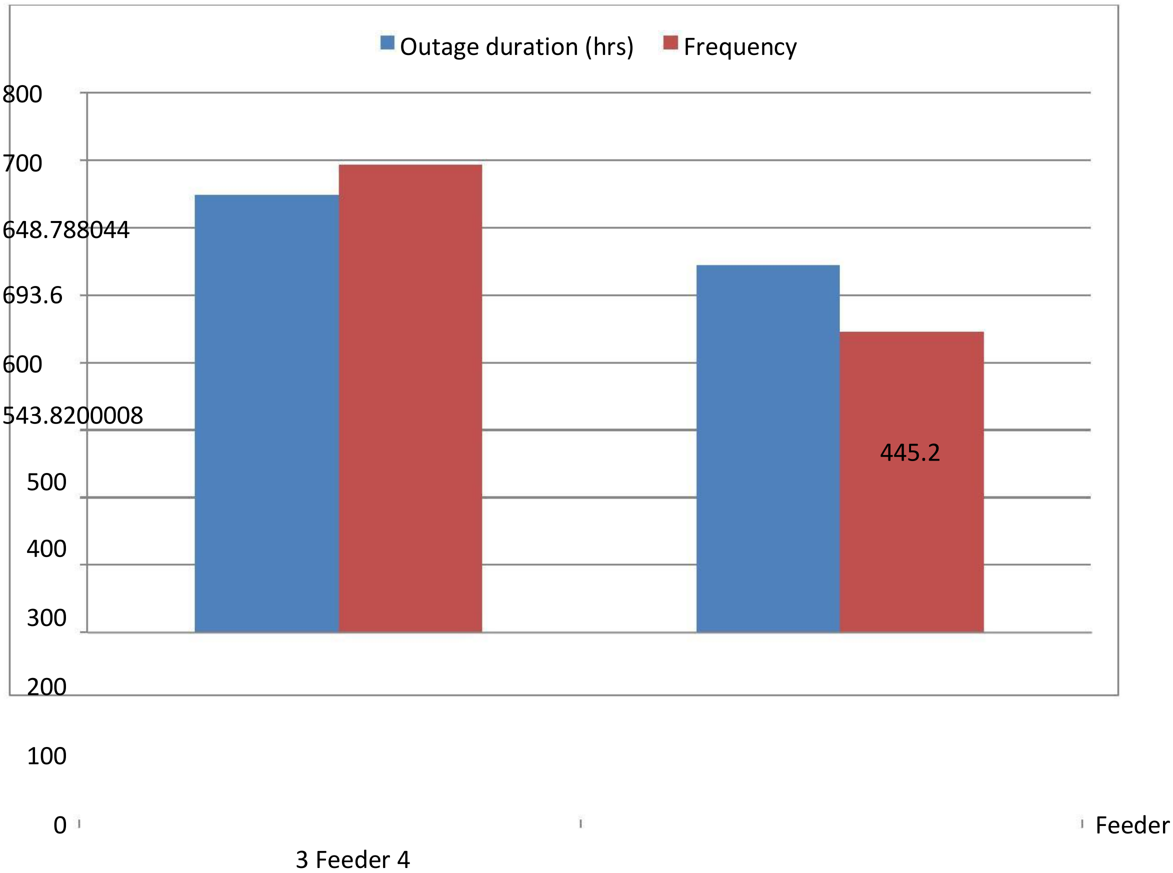


Figure 3.1: Outage duration and failure occurrence of each feeder.

Table 3.1: Radial system reliability indices for each feeder

Substation Feeders	Outage duration (hrs)	Frequency (occurrence)	Failure rate λ (Failures/year)	Annual outage duration U (hrs/yr)
Feeder 3	648.788044	693.6	0.0855112656	55.478687
Feeder 4	543.820001	445.2	0.0541857652	29.467303

In the normal conditions of the circuit, there are no disconnects on the main line. The only protections are the fuses that connect the main feeders and the lateral distributors. Hence, any fault on the main line will require the system to be isolated from the main breaker. The reliability assessment of each feeder can be calculated by considering the impact of each section and load point on the corresponding load point. Let us to examine the reliability assessment of each feeder.

First, the impact of each section failure on the load point's reliability is considered. Any section failure will result in power outage for load point since there are no disconnects on the main distribution lines. Then the outage duration r (hours) of each feeder is assessed. Using the failure occurrences of the feeder, its failure rate λ (f/yr) is determined. Using the failure rate and repair time, the annual outage duration U (hrs/yr) for each feeder is obtained.

Secondly, the impact of each lateral distributor's failure on the load point is considered. Since, each lateral is connected to the main feeder through fuse; a fault on any lateral will be introducing impact on the other load point. If there is a fault on the load point, the power from the main feeder is shutdown to repair the fault; its reliability impact will be added to the system. Adding the impact of each section and lateral distributor, the average failure rate, average outage duration, and annual outage duration for the main feeders can be calculated as by using equation (9), (10) and (11).

$$\lambda_s = \sum_i \lambda_i \qquad (9)$$

$$U_s = \sum \lambda_i r_i \qquad (10)$$

$$r_s = \frac{U_s}{\lambda_s} \qquad (11)$$

From the above equations the other parameters of each feeder were calculated as shown in the Table 3.2.

Table 3.2: The main feeder availability and unavailability indices

S/Station	Ni		648.788 r_i	$\lambda_i * N_i$	$U_i * N_i$	ASAI (%)	ASUI (%)
Feeder 3	6541	0.085511		559.3294	362886.092	92.594	7.4063
Feeder 4	4129	0.054186	543.82	223.7332	121670.494	93.792	6.208
Total	**10670**					**93.193**	**6.807**

The costumer load point indices are calculated, related to the unsupplied energy and costs. Those are the expected Energy Not Supplied (EENS), the Expected interruption Cost (EIC) and the Average Energy Not Supplied values are shown in Table 3.3. The priority order based on the EIC was used for load curtailment level; the EIC is the average monetary impact on the customers at a load point. This higher the EIC the higher priority this load may have, because a load curtailment at that load point will contribute to higher economic cost.

Table 3.3: Expected Energy not supplied and Interruption Costs indices for each feeder.

Substation Feeders	Expected Energy not supplied (MW hr/yr)	Expected Interruption Cost EIC (m$ /yr)	Average Energy Not Supplied (KW hr/yr. ca.)
Feeder 3	1843.73952	1.58043808	281.87426
Feeder 4	1175.52185	1.00764752	284.69892
Total	**3019.26137**	**2.58808558**	283.28659

From the above table each index of the main feeder provides different information and some indices are more important than others. The main feeder indices are useful in assessing the load point impact of system modifications and provide input to reliability evaluation at the actual customer level. Furthermore, there are the system reliability indices which provide valuable information on the overall ability of the system to supply the customer load. The probability of a customer receiving uninterrupted power supply can be accessed from the indices of Table 3.2 and Table 3.3. The higher the value of the reliability indices the higher is the unreliability at the corresponding bus. Using the data from the above table, the overall base case reliability indices can be calculated as shown in Table 3.4:

Table 3.4: DIgSILent Simulation Result of Overall System Indices Values.

```
|              |                                                         |  DIgSILENT  | Project:
|              |                                                         | PowerFactory |-------------------------------
|              |                                                         |   14.0.524  | Date:  6/18/2016             |
| Reliability Assessment                                                                                                  |
| -                                                                                                                       |
| - Network, connectivity analysis                                                                                        |
| Selection    = Whole System                                                                                             |
| Yes  = Common mode                          | Yes  = Independent second failures                                        |
| Yes  = Busbars / terminals                  | Yes  = Double earth faults                                                |
| Yes  = Lines / cables                       | No   = Maintenance                                                        |
| Yes  = Transformers                         |                                                                           |
| Study Case: Study Case                                                                       | Annex:               / 1  |
| System Summary                                                                                                          |
| System Average Interruption Frequency Index      :  SAIFI: =  608.168255 1/Ca                                           |
| Customer Average Interruption Frequency Index    :  CAIFI: =  608.168255 1/Ca                                           |
| System Average Interruption Duration Index       :  SAIDI: =  597.476    h/Ca                                           |
| Customer Average Interruption Duration Index     :  CAIDI: =    0.982    h                                              |
| Average Service Availability Index               :  ASAI:  =    0.9317949965                                             |
| Average Service Unavailability Index             :  ASUI:  =    0.0682050035                                             |
| Energy Not Supplied                              :  ENS:   = 2933.692    MWh/a                                          |
| Average Energy Not Supplied                      :  AENS:  =    0.275    MWh/Ca                                         |
| Average Customer Curtailment Index               :  ACCI:  =    0.198    MWh/Ca                                         |
```

4. CONCLUSION

The result of the study concluded that the base case system indices; SAIDI is 597.476 hr/customer year suggesting that system's average interruption duration for each customer is 597.476hr during a year, SAIFI is 608.168 inter./customer year suggesting that system's average interruption frequency for each customer is 608.168 during a year, CAIDI is 0.982 hrs/ customer interruption, suggesting system's average interruption duration for the customers that experience interruption is 0.982 hrs during a year and system availability and unavailability are 93.193% and 6.803% are respectively . Also, the expected energy not supplied (EENS) for the base case system due to the failures is 2933.692MWh/yr and the energy not supplied per customer is 168.9396kWh/yr. And finally, the expected interruption cost is 1.5333764millions $/yr during a year. The system reliability indices show that Debre Markos distribution system is unreliable distribution system.

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